Assumptions to the Annual Energy Outlook 2026: Industrial Demand Module

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Overview

The National Energy Modeling System's (NEMS) Industrial Demand Module (IDM) estimates U.S. energy consumption by energy source (fuels and feedstocks) in the *Annual Energy Outlook 2026* (AEO2026) for 18 manufacturing and 6 nonmanufacturing industries. The IDM subdivides manufacturing industries further into energy-intensive manufacturing industries and non-energy-intensive manufacturing industries (Table 1). The IDM models manufacturing industries through either a detailed process-flow or an end-use accounting procedure. The IDM models the non-manufacturing industries with less detail because the processes are simpler and fewer data are available. The petroleum refining industry is not included in the IDM because the NEMS Liquid Fuels Market Module (LFMM) models it separately. The IDM calculates energy consumption for the four census regions (Table 2) and disaggregates regional energy consumption to the nine census divisions based on fixed (historical) shares from our State Energy Data System (SEDS). The IDM uses the latest published SEDS year (2023 for AEO2026) to determine these census-division shares.[1] The IDM runs from the base year 2022 through 2050.

Table 1. Industry categories and North American Industry Classification System (NAICS) codes

Industry	NAICS code	Industrial Demand Module (IDM) industry code
Energy-intensive manufacturing		
Food products	311	7
Grain and oilseed milling	3112	
Dairy product manufacturing	3115	
Animal processing	3116	
Other food products	311 not elsewhere classified	
Paper and allied products	322	8
Bulk chemicals	Portions of 325	9
Organic (NAICS 32511, 32519)	325110, 32519	
Inorganic	325120–325180	
Resins (NAICS 3252)	3252	
Agricultural (NAICS 3253)	3253	
Glass and glass products	3272	10
Cement and lime	327310, 327410	11
Iron and steel	331110, 3312, 324199	12
Aluminum	3313	13

Industry	NAICS code	Industrial Demand Module (IDM) industry code
Non-energy-intensive manufacturing		
Metal-based durables	332–336	
Fabricated metals	332	14
Machinery	333	15
Computers and electronics	334	16
Transportation equipment	336	17
Electrical equipment, appliances, and components	335	18
Wood products	321	19
Plastic and rubber products	326	20
Light chemicals	325 excluding bulk chemicals (3254–3256, 3259)	21
Other non-metallic minerals	327 excluding cement and lime and glass (3271, 327320, 327330, 327390, 327420, 3279)	22
Other primary metals	331 excluding steel and aluminum (3314, 3315)	23
Miscellaneous finished goods	All other manufacturing industries (312–316, 323, 324121, 324122, 324191, 337, 339)	24
Non-manufacturing industries		
Agriculture, crop production, and support	111,1151	1
Agriculture, other	112, 113, 1152, 1153	2
Coal mining	2121	3
Oil and natural gas extraction	211	4
Metal and non-metallic mining	2122, 2123	5
Construction	23	6

Data source: U.S. Energy Information Administration; U.S. Department of Commerce; U.S. Census Bureau; and North American Industry Classification System (NAICS) (2017)—United States (Washington, DC, 2017)
Note: NAICS 324199 contains merchant coke ovens, which we consider part of the iron and steel industry.

Table 2. Census regions, census divisions, and states

Census region	Census divisions	States
1 (East)	1, 2	Connecticut, Maine, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont
2 (Midwest)	3, 4	Illinois, Indiana, Iowa, Kansas, Michigan, Minnesota, Missouri, North Dakota, Nebraska, Ohio, South Dakota, Wisconsin
3 (South)	5, 6, 7	Alabama, Arkansas, Delaware, District of Columbia, Florida, Georgia, Kentucky, Louisiana, Maryland, Mississippi, North Carolina, Oklahoma, South Carolina, Tennessee, Texas, Virginia, West Virginia
4 (West)	8, 9	Arizona, Alaska, California, Colorado, Hawaii, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington, Wyoming

Data source: U.S. Census Bureau, *2010 Census Regions and Divisions of the United States*—United States (Washington, DC, 2021)

The IDM models most industries as three separate but interrelated components:

- Process and assembly (PA)
- Buildings (BLD)
- Boiler, steam, and cogeneration (BSC)

The IDM calculates the PA component by end-use for all but five manufacturing industries. We calculate these five industries by production process (process flow):

- Paper
- Glass
- Cement and lime
- Iron and steel
- Aluminum

The BSC component satisfies the steam demand from the PA and BLD components. In some industries, the PA component produces byproducts that the BSC component consumes. The iron and steel, paper, and aluminum industries determine boiler and combined-heat-and-power (CHP) fuel use in the PA step.

The IDM base year is currently 2022, which is the year of the latest available *Manufacturing Energy Consumption Survey* (MECS).[2] The U.S. Energy Information Administration's (EIA) Office of Energy Statistics conducts the MECS every four years, and we update the IDM base year when a new MECS becomes available.

The IDM does not model petroleum refining (NAICS 32411), which the LFMM models in detail, but the manufacturing total does contain the projected petroleum refining energy consumption. In addition, projections of lease and plant fuel, energy used to liquefy natural gas, and fuels consumed in cogeneration in the oil and natural gas extraction industry (NAICS 211) are calculated in other modules.

Key assumptions—manufacturing

The IDM primarily uses a bottom-up modeling approach. An energy accounting framework traces energy flows from fuels to an industry's output. The IDM depicts the manufacturing industries, except for petroleum refining, with either a detailed process-flow or an end-use approach. Generally, industries with uniform products use a process-flow approach, and those with varied products use an end-use approach.

Five industries use a process-flow approach:

- Paper
- Glass
- Cement and lime
- Iron and steel
- Aluminum

Other industries use an end-use approach:

- Food

- Bulk chemicals
- The five metal-based durables industries (transportation equipment, machinery, computers, electrical equipment, and fabricated metals)
- Wood products
- Plastic and rubber products
- Light chemicals
- Other non-metallic minerals
- Other primary metals
- Miscellaneous finished goods (includes beverages, tobacco, furniture, pharmaceuticals, paints, soaps, cleaning products, textiles, and other miscellaneous products)

Process and assembly component for end-use submodules

Most manufacturing industries are modeled as end-use industries. End-use industries usually have several different products, which makes specifying a manageable number of process steps impossible. As a result, we model end-use industry energy consumption by general industrial processes, such as heating, cooling, or machine drive, instead of by specific process steps. The IDM models end-use process and assembly (PA) energy consumption at the census-region level and aggregates to the national level.

For manufacturing industries modeled using the end-use approach, the PA component models each major production end use through an evolving energy intensity, or unit energy consumption (UEC), defined as the amount of energy required to produce one dollar worth of output for a given process.

For end-use industries, the IDM establishes baseline UECs in the base year (currently 2022). The IDM calculates base year UECs for each manufacturing end-use process and each region by dividing MECS energy consumption data by industrial shipments from the NEMS Macroeconomic Analysis Module (MAM).

The IDM characterizes each major end use in later years by using technology possibility curves (TPCs) to estimate UECs (Table 3). A TPC represents the assumed average annual rate of change of energy intensity in an energy end use (for example, natural gas-fired heating). Each TPC for new and existing capacity varies by industry, end-use, and region. We developed these assumed rates using professional engineering judgments about energy characteristics, years of availability, and market adoption rates for new process technologies. Table 3 shows median UECs for existing equipment in 2022 and relative energy intensity for existing technology in 2050 and new technology for both 2022 and 2050. However, the IDM calculates a unique TPC for each industry, end-use, vintage, and region.

Table 3. Median unit energy consumptions (UECs) and relative energy intensities (REIs) for end-use manufacturing

End use	Fuel	UEC 2022 (trillion British thermal units per billion 2012$ of shipments)	REI 2050 existing	REI 2022 new	REI 2050 new
Heat	Natural gas	0.243	0.862	0.965	0.830
Heat	Electricity	0.023	0.929	0.983	0.938
Heat	Steam	0.375	0.862	0.965	0.829
Refrigeration	Electricity	0.043	0.923	0.966	0.900

Machine drive	Natural gas	0.029	0.882	0.970	0.829
Machine drive	Electricity	0.225	0.929	0.983	0.909
Electrochemical processes	Electricity	0.009	0.919	0.947	0.642
Other	Natural gas	0.019	0.893	0.969	0.845
Other	Electricity	0.009	0.922	0.983	0.903

Data source: U.S. Energy Information Administration, *2022 Manufacturing Energy Consumption Survey* (Washington, DC, August 2021)

Note: This table shows median UEC values for existing equipment in 2022 and REIs, illustrating the magnitude of UECs and REI values. We estimate UECs and REIs for each industry, region, and end use. The medians represent the median for a particular fuel and end use among all industries with that end use and fuel. We estimate the medians independently.

UEC 2022 is the energy consumption for region, industry, and end use divided by regional shipments of that industry.
REI 2050 existing is the ratio of 2050 energy intensity to 2022 energy intensity for existing facilities in the Counterfactual Baseline case.
REI 2022 new is the ratio of energy intensity in 2022 for new, state-of-the-art facilities to energy intensity in 2022 for existing facilities in the Counterfactual Baseline case.
REI 2050 new is the ratio of energy intensity in 2050 for new, state-of-the-art facilities to energy intensity in 2022 for existing facilities in the Counterfactual Baseline case.

To simulate technological progress and adoption of more energy-efficient technologies, the IDM adjusts each UEC every projection year, based on the assumed TPC for each end-use step. We derive a TPC from assumptions about the relative energy intensities of productive capacity by vintage (new capacity relative to existing stock each year) or over time (new or surviving capacity in 2050 relative to the 2022 stock). Over time, each UEC for new capacity changes, and the TPC is the rate of change. The IDM also assumes every UEC of the surviving 2022 capital stock declines over time because of retrofitting, but retrofitting existing capacity will always be more energy-intensive than new capacity.

REIs and TPCs are general assumptions we make about new technology adoption in the manufacturing industry and the associated change in energy consumption without characterizing individual technologies. This approach also assumes that energy consumption at industrial plants will change when owners do any of the following:

- Replace old equipment with new, more efficient equipment
- Add new capacity
- Add new products
- Upgrade energy management practices

We cannot directly attribute increased efficiency to technology choice because these industries are complex. Instead, the IDM uses the REIs and TPCs to characterize intensity trends for bundles of technologies available for the end-use industries. TPC and REI calculations for industries can either decline at a fixed percentage or vary over time, reflecting how changes in fuel price over time might affect the rates at which energy intensities decline.

The module distinguishes each UEC by three vintages of capital stock. We assume that new vintage stock will consist of state-of-the-art technologies that have different efficiencies from the existing capacity. As a result, the energy required to produce a unit of output using new capacity is less than what the existing capacity requires. The old vintage capacity consists of capacity that exists in the IDM base year and continues to operate after adjusting for assumed retirements each year (Table 4). In each projection year, the IDM adds new production capacity when necessary to ensure that sufficient remaining and new capacity is available to meet an industry's regional output as determined in the MAM. Middle vintage capacity is capacity added after the base year through the year before the current projection year.

Table 4. Annual retirement rates for end-use industries

Industry	Retirement percentage
Food products	1.7%
Bulk chemicals	1.7%
Metal-based durables	1.3%
Wood products	1.3%
Plastic and rubber products	1.3%
Light chemicals	1.3%
Other non-metallic minerals	1.3%
Other primary metals	1.3%
Miscellaneous finished goods	1.3%

Data source: SAIC's Industrial Demand Module base year update with *Manufacturing Energy Consumption Survey 2006* data and unpublished data prepared for our Office of Integrated Analysis and Forecasting (Washington, DC, August 2010)
Note: *Metal-based durables* includes fabricated metal products, machinery, computer and electronic products, transportation equipment, and electrical equipment/appliances.

We adjusted some industries' 2050 new equipment UECs to allow for air source heat pumps to partially replace natural gas for process heat. For food, rubber and plastic products, and miscellaneous finished goods, a portion of the new equipment for process heat that would have been served by natural gas in 2050 is assumed to be served by an electric-powered air source heat pump instead. Consequently, the natural gas 2050 UEC for new equipment in these industries is lower than it would have been because of the heat pump replacement, and the electricity UEC in these industries is higher. Other industries' process heat needs were assessed to require higher temperatures that could not be effectively served by commercially available heat pumps. Because the 2050 new equipment UEC changes and the 2022 new equipment doesn't change, the TPCs of new equipment also change: the natural gas process heat TPC is lower, and the electricity process heat TPC is higher.

Table 5 shows the assumed air-source heat pump penetration (share of process heat demand met by heat pumps) in 2050 and the heat pump coefficient of performance (COP) by industry. The COP is the ratio of total energy provided to process heat divided by the electricity needed for the heat pump. The COP is greater than one because heat is being transferred from one place to another, not produced in a conventional heating process.

Table 5. Assumed penetration and coefficient of performance for air-source heat pumps, 2050

Industry	Air-source heat pump penetration 2050	Heat pump coefficient of performance
Food	25%	2.5
Rubber and Plastic	20%	2.0
Miscellaneous Finished Goods	20%	2.0

Data source: U.S. Energy Information Administration staff calculations, based on a review of heat pump literature

Petrochemical feedstocks requirement

The IDM estimates feedstock requirements for the major petrochemical olefin products, such as ethylene, propylene, and butadiene. The primary feedstocks used to produce the olefins are hydrocarbon gas liquids (HGLs) (ethane, propane, and butanes) and heavier, oil-derived petrochemical feedstocks (naphtha and other oils). These feedstocks are converted to olefins, primarily ethylene, in a chemical process known as *cracking*. The IDM also models demand for natural gas feedstock to produce methanol. Natural gas feedstock to produce hydrogen and ammonia is modeled in the Hydrogen Market Module (HMM). Biomass is a potential raw material source for chemicals, but the module assumes biomass-based capacity is unavailable during the projection period because of economic barriers. The type of feedstock determines the energy requirements for heat and power to produce the chemicals, as well as the product yield.

We base historical HGL and heavy petrochemical feedstock consumption on SEDS data, and we base 2025–2027 feedstock consumption on *Short-Term Energy Outlook* (STEO) forecasts[3] and external data sources and analysis. From 2028 on, the sum of HGLs and heavy feedstock consumption changes based on shipments of petrochemicals. We assume a 5% baseline recycle rate that reduces ethylene demand. This recycle rate changes as a function of crude oil price. We assume all new olefin production capacity in the United States is light-feedstock based. However, under certain price conditions, some light-feedstock consumption is allowed to switch over to heavy-feedstock consumption. This ability represents how certain cracking facilities can switch between HGLs and heavy feedstock.

This light-heavy feedstock switching is represented in the IDM as switching between using ethane (light) and naphtha (heavy) feedstocks in ethylene production (ethylene is the desired olefin product). Ethane-naphtha switching depends on the relative price of each feedstock (derived from linear regressions of historical chemical price data and the West Texas Intermediate crude oil price), the chemical cracking yields of each feedstock (Table 6), and the prices of the coproducts from the respective cracking reactions. The IDM calculates the net feedstock cost needed to produce one metric ton of ethylene from ethane; it subtracts the value of the side products produced from the ethane cracking from the cost of the ethane consumed to get the net feedstock cost to produce ethylene from ethane. The IDM calculates the same value for naphtha feedstock by subtracting the value of the side products yielded from producing one metric ton of ethylene from naphtha from the cost of the naphtha feedstock consumed. We compare the net costs of each feedstock, and we consider the feedstock with the lower net feedstock cost to be more economical. We assume the differences in process and in capital costs are negligible.

Table 6. Chemical mass yields for cracking ethane and naphtha
metric tons of product per metric ton of feedstock

Products	Ethane	Naphtha
Hydrogen	0.0591	0.0097
Methane	0.0704	0.1694
Ethylene	0.8091	0.3867
Propylene	0.0194	0.1547
Butadiene	0.0178	0.0476
Butylene and butanes	0.0081	0.0507
Benzene	0.0081	0.0437
Toluene	0.0008	0.0166
Xylene	0.0000	0.0224
Other aromatics	0.0073	0.0735
Fuel oil	0.0000	0.0251

Data source: American Chemistry Council, *Ethylene Product Stewardship Manual*, December 2004

The amount of capacity that can switch between ethane and naphtha is based on a few assumptions. First, we assume the baseline naphtha feedstock demand is constant from 2028 on, equal to 90% of 2019 naphtha feedstock consumption, or about 550 trillion British thermal units (TBtu). All of this capacity is in the West South-Central Census Division. Second, some cracking capacity can quickly switch between cracking ethane and naphtha, depending on the relative net feedstock costs. The baseline *quick-flex* capacity is the amount of ethylene produced from naphtha in 2011 minus the ethylene produced from the nonflexible (naphtha-only) capacity, or about 2.605 million metric tons of ethylene. Quick-flex capacity is all located in the West South-Central Census Division.

In any year, where either ethane or naphtha is more economical, 50% of existing flex capacity (after capacity additions) will change to the most economical feedstock if that feedstock is not already being used in 100% of the quick-flex capacity. Some flexible capacity, which cracks only ethane in the base year, can switch more slowly. Given a sustained price signal where the net feedstock costs for ethane are higher than the net feedstock costs for naphtha for three consecutive years, some of the *slow-flex* capacity will switch over to quick-flex capacity after a construction period of two more years. This switch represents cracking facilities that need substantial investment to be able to crack naphtha. The baseline slow-flex capacity is the amount of ethylene produced from naphtha in 2004 minus the amount of ethylene produced from naphtha in 2011, or about 5.513 million metric tons of ethylene. Slow-flex capacity is converted to quick-flex capacity in increments of 1.102 million metric tons of ethylene capacity. We assume no new slow-flex capacity will be built.

For 2022–27, we estimated the natural gas feedstock forecast based on third-party methanol production capacity estimates and data from the 2018 MECS (2022 MECS data were incomplete), as well as changes in shipments in selected sectors. We similarly use ethylene cracker project data for both the HGL (light) and naphtha (heavy) feedstock forecast for 2022–27. In addition, the IDM breaks down HGL feedstocks into components (ethane, propane, propylene, and butanes). The IDM holds propylene consumption constant at about 300,000 barrels per day throughout the projection period, close to current U.S. refinery propylene production levels.

For chemical feedstocks, energy intensity does not change over time: the IDM assumes every feedstock TPC is zero. Unlike most other processes in manufacturing PA components, chemical yields follow basic chemical stoichiometry that allows for specific yields under set conditions of pressure and temperature.

Hydrogen feedstocks consumption

Hydrogen is now part of NEMS as an explicit feedstock and fuel. Previously, industrial hydrogen consumption was implicitly accounted for in natural gas feedstock consumed in the bulk chemicals industry. We now assume a portion of that natural gas feedstock consumption (that allocated to NAICS 325199 in MECS) is used for production of methanol and assume the rest of the natural gas feedstock is used to produce hydrogen. Now, instead of modeling the natural gas used to produce hydrogen in IDM, we model the industrial demand for hydrogen directly.

On-purpose hydrogen production and the associated energy consumption is now modeled in the new Hydrogen Market Module (HMM). HMM energy consumption (both fuel and feedstock) is included in the industrial total and bulk chemicals totals in NEMS tables unless explicitly specified, much in the same way refining is industrial consumption but is modeled in a module separate from IDM. See the HMM assumptions document for more details.

The sum of IDM, LFMM, and HMM primary consumption (defined as consumption excluding hydrogen, to avoid double-counting of energy) still adheres to SEDS and STEO benchmarking.

We estimated base year hydrogen consumption (Table 7) and supply (Table 8) in the chemical subsector using a combination of MECS data, U.S. Geological Survey data,[4] and a steam methane reformer production factor of 0.1573 MMBtu feedstock natural gas per kilogram hydrogen.[5] We use the baseline hydrogen consumption and onsite production as input to the IDM. The baseline consumption then grows with chemical subsector shipments. The bulk chemicals industry is the only industry that consumes hydrogen in the base year, although the iron and steel industry has a technology that uses hydrogen feedstock and can be chosen to deploy in later years.

Table 7. Base year hydrogen consumption by bulk chemical subsector
trillion British thermal units

Bulk chemicals subsectors	Region 1	Region 2	Region 3	Region 4	U.S. total
Inorganics	4	0	13	1	18
Organics	0	0	73	1	74
Resins	1	0	73	0	74
Agricultural chemicals	0	95	259	1	355

Data source: U.S. Energy Information Administration

Table 8. Base year hydrogen onsite production by bulk chemical subsector

trillion British thermal units

Bulk chemicals subsectors	Region 1	Region 2	Region 3	Region 4	U.S. total
Inorganics	4	6	149	19	178
Organics	0	0	73	1	74
Resins	1	0	73	0	74
Agricultural chemicals	0	95	227	1	323

Data source: U.S. Energy Information Administration

Although HMM models on-purpose hydrogen production and price, IDM models byproduct hydrogen production. The base year byproduct hydrogen production is the difference between historical hydrogen onsite production and consumption in all sectors (currently industrial, refining, and transportation, with the refining data coming from the *Petroleum Supply Annual*).[6] Byproduct production then grows as a function of the consumption of ethane, propane, and naphtha feedstocks. We calculate byproduct production using the cracking yields in Table 6 for ethane and naphtha, and a cracking yield of 0.0296 TBtu hydrogen per TBtu propane (based on an assumed stoichiometric 1 mole of hydrogen produced per mole of propane cracked).

Process and assembly component for process-flow submodules

Many of the energy-intensive manufacturing industries are modeled using a process-flow approach in which each industry possesses a suite of detailed technology choices for each process flow within a given process-flow industry (iron and steel, aluminum, glass, pulp and paper, and cement and lime). Instead of setting the energy intensity for each process and end use to evolve according to a TPC, the process-flow submodules use technology choice for each process flow industry. Initially, technology characteristics (for example, expenditures, energy intensities, and utility needs) were derived from the Consolidated Impacts Modeling System (CIMS) database that the Pacific Northwest National Laboratory prepared, but they are updated every few years. These characteristics define the energy requirements for each technology.[7] Depending on the industry, we calibrate these data using inputs from the U.S. Geological Survey (USGS) of the U.S. Department of the Interior, the Portland Cement Association, and our latest MECS.[8,9]

The process-flow submodules calculate surviving capacity, which is based on retirements. The process flow submodules also calculate needed capacity, which is based on shipments and surviving capacity. The IDM assumes that baseline capacity (as of 2022) will retire at a linear rate over a fixed period (20 years) and that incremental, or added, capacity will retire according to a logistic survival function with a maximum life of 30 years. An analyst can adjust parameters to obtain the exact shape of the logistic S-curve. We obtained equipment characteristics used for investment decisions (capital and operating costs, energy use, and emissions) for newly built equipment from the CIMS database. Each step of the process flow allows several technology choices whose fuel type and efficiency are known at the national level, based on available EIA data.

We benchmark the process-flow submodules to the 2022 MECS data for each fuel in each of the five process-flow industries. This process ensures a historically accurate fuel consumption baseline for the cement and lime, pulp and paper, aluminum, iron and steel, and glass industries modeled in the IDM. Steam coal and metallurgical (met) coal consumption are exceptions, which are benchmarked to base year data from our *Quarterly Coal Report*.[10]

Pulp and paper industry

The pulp and paper industry converts wood fiber to pulp, and then it manufactures paper, paperboard, and consumer products that are generally sold in the domestic marketplace. The industry produces a full line of paper and board products, as well as dried pulp, which it sells as a commodity product to domestic and international paper and board manufacturers. This industry includes several manufacturing steps and technologies:

- Wood preparation removes bark and chips logs into small pieces.
- Pulping removes fibrous cellulose in the wood from the surrounding lignin. Pulping can occur with a chemical or a mechanical process.
- Pulp washing with water removes the cooking chemicals and lignin from the fiber.
- Drying, liquor evaporation, effluent treatment, and other miscellaneous steps are part of the pulping process. Pulp is sent to a pressing section to squeeze out as much water as possible by mechanical means. The pulp is compressed between two rotating rolls, and the amount of water removed depends on the design and speed of the machine. When the pressed pulp leaves the pressing section, it has about a 65% moisture content. Various techniques for drying are available, and each has different energy consumption characteristics.
- Bleaching is required to produce white paper stock.

Paperboard, newsprint, coated paper, uncoated paper, and tissue paper are final products. Producing final products requires drying, finishing, and stock preparation.

Glass industry

In the glass industry submodule, each step of the glass-product processes modeled in the IDM allows several technology choices with known fuel type and efficiency, as well as other known operating characteristics.

For flat glass (NAICS 327211), the process steps consist of batch preparation, furnace, form and finish, and tempering. For pressed and blown glass (NAICS 327212), the process steps are preparation, furnace, form and finish, and fire polish. For glass containers (NAICS 327213), the process steps are preparation, furnaces, and form and finish. We do not model the final category (glass from glass products–NAICS 327215) as a process flow industry with technology choices but instead model it as an end-use industry that employs a UEC and TPC for each fuel to capture energy intensity changes over time.

The glass submodule uses several technologies. Not all of the technologies below are available to all processes:

- The preparation step (collection, grinding, and mixing raw materials, including recycled glass known as *cullet* for container glass) uses either a standard set of grinders and motors or advanced, computer-controlled grinders. We assume a 31% recycle rate for container glass cullet over the entire projection based on information compiled by the U.S. Environmental Protection Agency,[11] and we assume the other kinds of glass use 100% virgin glass.

- The furnaces, which melt the glass, are air-fueled or oxy-fueled burners that use natural gas. Electric-boosting furnace technology is also available. Direct-electric (or Joule) heating is available for fiberglass production.
- The form and finish process applies to all glass products, and the technology options are high-pressure, natural gas-fired, computer-controlled technology, or basic technology.
- No technology choice exists for the tempering step (flat glass) or the polish step (blown glass). We added placeholders for more efficient future technology choices, but their introduction into these processes was rather limited.

As with the other submodules, the technology options in each of these process steps evolves over time and depends on the relative cost of equipment, cost of fuel, and fuel efficiency. We added oxy-fueled burners as a retrofit to the burner technologies, and we determine their additive impact by using the relative price of natural gas and electricity.

Combined cement and lime industry

Each step in the cement process flow (raw material grinding, kiln, and finish grinding) can use several technologies, and we know each step's fuel types and efficiency at the national level because regional fuel breakouts are estimated using EIA data. Cement now has only dry-mill processes; we assume the use of wet-mill processes to be negligible. The technology choices within each group are:

- Raw materials grinding
  - Ball mill or roller mill
- Kilns
  - Rotary long with preheat, precalcining, and computer control
  - Rotary preheat with high-efficiency cooler
  - Rotary preheat and precalcine with efficient cooler
  - Brimstone, a low-carbon technology that uses calcium silicate instead of limestone
- Kilns (burners)
  - Coal-fired: standard or efficient (no new builds after 2025)
  - Natural gas-fired: standard or efficient
  - Petroleum coke-fired: standard (no new builds)
  - Alternative fuel such as municipal solid waste (MSW): standard
- Finish grinding
  - Ball mill: standard or with high-efficiency separator
  - Roller mill: standard or with high-efficiency separator

The technology slate in each process step evolves over time and depends on the relative cost of equipment, cost of fuel, and fuel efficiency.

We calibrate the IDM base year technology slate for cement using data from the 2022 MECS, the CIMS database, the Portland Cement Association, and the USGS. The IDM assumes imported clinker, additives, and fly ash make up a constant percentage of the finished product and displace some domestic clinker production, which lowers apparent energy use.

The IDM estimates lime energy consumption separately from cement, but it presents them together as the consolidated cement and lime energy consumption. We use the same methods for cement drive energy consumption and technology evolution in the lime industry with different, industry-specific equipment choices.

CCS cement retrofits

IDM has a modeling capability to capture CO_2 in existing (as of 2022) cement kilns throughout the contiguous United States. Note that carbon capture and sequestration (CCS) equipment cannot be built with new cement capacity in the projections by assumption. For this submodule, cost data (capital and operations and maintenance [O&M]) were extracted from the National Energy Technology Laboratory (NETL) database.[12] Fuel intensities (natural gas and electricity) employed in the CCS submodule are also based on this NETL data, and these fuel intensities provide the variability to the O&M costs for CCS equipment in the projections as fuel prices evolve.

CCS retrofits are modeled not on individual cement kilns but rather using CO_2 *Cost of Capture* distributions. These distributions were created by exponentially fitting the modified NETL cement retrofit cost data to create a CO_2 *supply curve* (cumulative CO_2 captured in thousand metric tons versus the cost of capture in $/metric ton), and these curves are used as the basis for determining the amount of retrofit kiln capacity installed each year given a CO_2 price from the CCATS (Carbon Capture, Allocation, Transportation, and Sequestration) module in NEMS. Upon receiving a CO_2 price from the CCATS module, the IDM assesses where on the CO_2 supply curve the received price falls, which in turn determines what fraction of kiln capacity in a given census region will be economically eligible for building CCS retrofits. Note, however, that this *economic potential* is diminished by an assumed constant *technical potential*, which reduces the retrofit capacity additions significantly. This technical potential accounts for the fact that there is currently no cement facility engaged in planning or building retrofit CCS capacity. Previously, one plant in the Midwest had secured at least preliminary federal funding to assist in CCS construction, but now the project has been canceled. No other cement plant has announced any intention of building CCS capacity.

One modification was made to the NETL capital investment cost computation. NETL assumes a 30-year payback period with 4.63% interest to compute the amortized capital cost (ACC). In the IDM, we assume a more realistic payback period of 12 years (which is the duration of the 45Q tax credit[13] for sequestering carbon detailed in the Inflation Reduction Act). This change increases the overall cost of CCS retrofits.

Iron and steel industry

The iron and steel industry includes several major process steps:

- coke production
- iron production
- steel production

- steel casting
- steel forming

Steel manufacturing plants are either integrated or nonintegrated. The classification depends on the number of major process steps performed in the facility. Integrated plants perform all the process steps, whereas nonintegrated plants, in general, perform only the last three steps.

The IDM uses a five-step process flow to estimate UEC values. Steps for crude steel production are different for steel made primarily from raw materials (primary steel) than for scrap steel reformed into new steel (secondary steel).

Crude primary steel is generally a two-step process:

1. Coke ovens convert metallurgical coal into coke.
2. Iron is reduced in a blast furnace with coke and limestone and is then charged into a basic oxygen furnace to produce crude steel.

Secondary steel is generally a one-step process. An electric arc furnace produces raw steel from an all-scrap (recycled materials) charge, which can be supplemented with direct-reduced iron (DRI). Like a blast furnace, DRI reduces iron but uses much lower temperatures than a blast furnace.

The steps to turn crude steel into finished products are the same for primary and secondary steel:

1. Crude steel is cast into blooms, billets, or slabs using continuous casting.
2. Steel is then hot rolled into various mill products. Some of these products are sold as hot-rolled mill products, while others are further cold rolled to impart surface finish or other desirable properties.

The technology slate in each of these process steps evolves over time and depends on the relative cost of equipment, the cost of fuel, and fuel efficiency. The latest CIMS database determines and calibrates the IDM base year technology slate based on the 2022 MECS and USGS physical output for 2022.

Producers switch from a blast furnace and basic oxygen furnace to an electric arc furnace when coal prices rise. If coal prices don’t rise or only rise slightly, the percentage of steel production from electric arc furnaces marginally increases over the projection period. Based on generally accepted industry trend outlooks, the proportion of steel production from blast furnaces and basic oxygen furnaces does not increase.

Aluminum industry

For the aluminum industry submodule, each step (alumina production, anode production, electrolysis for primary aluminum production, and melting for secondary production) has several technology choices for new capacity with known fuel types and efficiencies, as well as other operating characteristics. We know technology shares at the national level, and we base regional fuel breakouts on allocations from EIA data.

The aluminum industry has both primary and secondary production processes, which vary widely in their energy demands. Recently, secondary aluminum’s share of total aluminum production capacity has increased significantly relative to its historical share. Several primary smelters have closed during the past few years and may not reopen. Therefore, experts expect the share of secondary aluminum to constitute at least 75% of total aluminum output through 2050. We assume no new primary aluminum plants will be built in the United States before 2050, although very limited capacity expansion of existing primary smelters may occur.

Some technologies are options for both processes, and others are options for only one process:

- Primary smelting (Hall-Heroult electrolysis cell) is represented by four pre-bake anode technologies that denote standard and retrofitted choices and one inert anode-wetted cathode choice.
- Anode production, used in primary production only, is represented by three natural gas-fired furnaces under various configurations in forming and baking pre-bake anodes. Anodes are a requirement for the Hall-Heroult process.
- Alumina production (Bayer Process) is used in primary production only and selects between existing natural gas facilities and those with retrofits.
- Secondary production selects between two natural gas-fired melting furnaces: standard and high efficiency.

The technology slate in each of these process steps evolves over time and depends on the relative cost of equipment, cost of fuel, and fuel efficiency. We calibrate the latest IDM base year technology slate to CIMS bandwidth studies from the U.S. Department of Energy's Advanced Manufacturing Office,[14] the 2022 MECS, and USGS data on the physical production of primary and secondary aluminum. The submodule assumes all new capacity for aluminum production, both for replacement capacity and increased production needs, is either idled primary production capacity that comes back online or new secondary production capacity.

Buildings component

The total buildings energy demand by industry for each region is a function of regional industrial employment and output. The IDM estimates building energy consumption for building lighting, HVAC (heating, ventilation, and air conditioning), facility support, onsite transportation, conventional electricity generation attributable to the buildings sector, and other non-process uses. We divide space heating further to estimate how much energy steam and the direct combustion of fossil fuels provide. The submodule also estimates energy consumption in the buildings component for an industry based on regional employment and output growth for that industry using the 2022 MECS as a basis.

Boiler, steam, and cogeneration component

The steam demand and byproducts from the PA and BLD components are passed to the BSC component, which applies a heat rate and a fuel share equation to the boiler steam requirements to compute the required energy consumption (**Error! Reference source not found.**). The iron and steel industry and the pulp and paper industry are exceptions; these industries have independent BSC and cogeneration-related modeling that is calculated during the PA step.

The boiler fuel shares apply only to the fuels that are used in boilers for steam-only applications. The next section describes fuel use for the combined-heat-and-power (CHP) share of steam demand. The IDM assumes some fuel switching for the remainder of the boiler fuel use and calculates it with a logit-sharing equation, where fuel shares are a function of fuel prices.

For AEO2026, electric boilers and heat pumps combined are assumed to replace 10% of natural gas boilers and 20% of coal boilers by 2050. Adoption over the projection period occurs according to a logistic function until the desired shares are reached.

The IDM assumes byproduct fuels are consumed without regard to price and are independent of purchased fuels. The PA component estimates the production of byproduct fuels. We base the boiler fuel share equations and calculations on the 2022 MECS and information from the Council of Industrial Boiler Owners.[15]

CHP plants, which are designed to produce both electricity and useful heat, have been used in the industrial sector for many years. In this submodule, we base the CHP estimates for end-use industries on the assumption that the historical relationship between industrial steam demand and CHP will continue in the future and that the rate of additional CHP penetration will depend on the economics of retrofitting CHP plants to replace steam generated from existing non-CHP boilers. The technical potential for CHP is based on supplying steam requirements. We then determine capacity additions based on:

- The interaction of CHP investment payback periods (with the time value of money included) derived using operating hours reported in our published statistics
- Market penetration rates for investments with those payback periods
- Regional deployment of these systems as characterized by *collaboration coefficients*, which quantify the relative ease of installing and connecting CHP to the grid for a given region (Table 9)
- Assumed installed costs for the CHP systems (Table 10)

Table 9. Regional collaboration coefficients for CHP deployment

Census region	Collaboration coefficient
1	0.335
2	0.175
3	0.235
4	0.255

Data source: U.S. Energy Information Administration, Form EIA-860, *Annual Electric Generator Report*; **the A**merican Council for an Energy-Efficient Economy, 2017 State Energy Efficiency Scorecard (Washington, DC, September 2017)

Table 10. Cost characteristics of industrial CHP systems

System	Capacity (MW)	2022 overall heat rate (Btu/kWh)	2022 installed cost (2022$/kW)	2050 overall heat rate (Btu/kWh)	2050 installed cost (2022$/kW)
Reciprocating engine	1	9,210	$3,125	9,096	$3,101
	3	8,417	$2,586	8,313	$2,703
Gas turbine	5	12,185	$2,628	11,587	$2,626
	10	12,091	$2,020	11,485	$1,996
	25	9,720	$1,697	9,496	$1,647
	40	9,611	$1,448	9,154	$1,423
Combined cycle	100	6,749	$1,632	6,437	$1,643
	375	6,246	$1,383	5,962	$1,341

Data Source: Leidos, *Distributed Generation, Battery Storage, and Combined Heat and Power System Characteristics and Costs in the Buildings and Industrial Sectors* (Washington, DC, March 2024)
Note: MW=megawatts, Btu=British thermal units, kW=kilowatt, kWh=kilowatthours

CHP for steel, paper, and aluminum industries

For steel and paper, the IDM computes boiler and CHP capacity and generation as part of the PA step. Steam demand for each process is a non-energy demand for each process step. The submodule calculates the initial steam and CHP in the IDM base year based on historical Form EIA-860 data, and the submodule assumes a specific CHP share in the final projection year. Specific CHP and boiler technology shares in the IDM base year and final projection year are then chosen from a slate of user-assumed technologies with different fuels. In the intervening years, the IDM interpolates shares of CHP and boilers as well as technology shares.

For the aluminum industry, the structure is slightly different. The boiler step (including CHP) is a distinct process step in the manufacture of alumina from bauxite. We set initial boiler and CHP technology shares in the IDM base year based on research and analyst judgement.

Key assumptions—nonmanufacturing

The nonmanufacturing sector consists of three industries: agriculture, mining, and construction. These industries all use purchased electricity, natural gas, distillate, and gasoline. The construction industry also uses propane and other petroleum products such as asphalt and road oil, while the agriculture industry also uses propane and biomass. Except for oil and natural gas extraction, almost all of the energy use in the nonmanufacturing sector takes place in the PA step.

Unlike the manufacturing sector, the nonmanufacturing sector does not have a single source of data for base year energy consumption. Instead, we derive UECs for the nonmanufacturing sector from various sources of data collected by several government agencies.

For AEO2026, the UECs were updated for the year 2022 to be commensurate with the updates for manufacturing industry UECs using 2022 MECS data. To derive these baseline 2022 nonmanufacturing UECs, we used 2022 expenditure data by fuel for the agriculture and construction sectors along with the 2022 commercial fuel prices[16] to arrive at fuel consumption estimates. For the mining sector we used fuel consumption data directly.

Energy intensities, computed using these historical consumption values and shipments for year 2022, are used with projected shipments from the Macroeconomic Activity Module (MAM) to project future energy consumption. Energy intensities evolve over the projection with assumed TPCs for each fuel.

Agriculture subsector

NEMS models two broad subsectors of U.S. agriculture:

- Crop production (NAICS 111, 1151)
- Other animal and forestry production (NAICS 112, 113, 1152, 1153)

We extract baseline energy consumption data for the entire agriculture industry from 2022 expenditure data provided by the Economic Research Service (ERS) of the USDA (propane, motor gasoline, diesel, natural gas, purchased electricity, and oils and lubricants). We separated this data into the two agriculture sectors (crops and other agriculture) based on historical shipments from AEO2023.

Mining subsector

The mining subsector is made up of three parts: coal mining, metal and nonmetal mining, and oil and natural gas extraction. Energy use is based on the equipment and onsite vehicles used at the mine. All mine subsectors use extraction equipment and lighting, but only coal mines and metal and nonmetal mines use grinding and ventilation. Fuel consumption values for 2022 were directly extracted from the Economic Census data.[17]

For oil and natural gas extraction, natural gas used as lease and plant fuel makes up most of the fuel used for extraction and processing. The Natural Gas Market Module computes lease fuel and fuel used in natural gas processing plants. Both uses of natural gas are considered industrial consumption in the aggregate, but the IDM does not compute them. The IDM computes the other fuels in the oil and natural gas extraction sector, including fuel oil, distillate, and electricity, based on oil and natural gas production data from the Hydrocarbon Supply Module. Energy use depends on the fuel extracted, whether the well is conventional or unconventional (for example, extraction from tight and shale formations), percentage of dry wells, and well depth.

Construction subsector

The construction subsector consumes distillate, gasoline, electricity, propane, and other petroleum (lubricants). For AEO2026, parallel to the MECS update, we established a new historical base year (2022) using updated energy intensities. We used Economic Census data[18] to get fuel expenditures for combined fuel categories: motor gasoline and diesel, natural gas and propane, purchased electricity, and *all other fuels* (assumed to be lubricants). Data from a 2015 Statista report on Canada[19] was used to split the two combined fuel categories. Note, as in AEO2025, the bulk of asphalt consumption was moved from construction to the miscellaneous finished goods industry.

Legislation and Regulations

Inflation Reduction Act, 2022 (IRA2022)

IRA2022 extended the combined-heat-and-power (CHP) investment tax credit (ITC) from the Consolidated Appropriations Act of 2021 through the end of 2024. However, the IRA2022 also changed the ITC as it applies to 2023 on. Instead of a flat 10% credit, a project receives a baseline 6% ITC credit. If a project meets prevailing wage and apprenticeship requirements set out in the bill, this percentage is instead 30%.

Furthermore, if the project meets domestic material content requirements defined in the bill, the ITC increases by a further 10 percentage points, or by 2 percentage points if the project does not meet the material requirements.

Finally, if a project is in an energy community as defined in the bill, the ITC is increased by 10 percentage points. If the project is not located in an energy community, the ITC increases by 2 percentage points.

As a result, the possible ITC ranges from a minimum of 10% to a maximum of 50%.[20] The IDM uses the minimum ITC for the Counterfactual Baseline case and core side cases, given the time window for the new ITC structure compared with the planning time for industrial projects.

Consolidated Appropriations Act, 2021 (CAA2021)

CAA2021 extended the 10% CHP ITC from the Bipartisan Budget Act of 2018 through the end of 2023. It now applies for all qualifying CHP facilities that begin construction before January 1, 2024.[21]

Bipartisan Budget Act of 2018 (BBA2018)

BBA2018 retroactively extended the 10% CHP ITC from the Energy Improvement and Extension Act of 2008 (EIEA2008) through the end of 2021. The ITC in EIEA2008 originally spanned from 2008 through the end of 2016, but BBA2018 applied the ITC to all qualifying CHP facilities that began construction before January 1, 2022.[22]

The Energy Independence and Security Act of 2007 (EISA2007)

EISA2007 suspends motor efficiency standards established under the Energy Policy Act of 1992 (EPACT1992) for purchases made after 2011. This law increases or creates minimum efficiency standards for newly manufactured and imported general-purpose electric motors (Section 313 of EISA2007). The efficiency standards are raised for general-purpose, integral-horsepower induction motors, except for fire pump motors. Minimum standards were created for seven types of poly-phase, integral-horsepower induction motors and National Electrical Manufacturers Association (NEMA) design B motors (201–500 horsepower) that were not previously covered by EPACT standards. In 2013, the Energy Policy and Conservation Act was amended (Public Law 113-67), and efficiency standards were revised in a subsequent U.S. Department of Energy (DOE) rulemaking (10 CFR 431.25). For motors manufactured after June 1, 2016, efficiency standards for current regulated motor types[23] were expanded to include 201–500 horsepower motors. In addition, special- and definite-purpose motors from 1–500 horsepower and NEMA Design A motors from 201–500 horsepower were subject to efficiency standards. AEO models 2014 regulations by modifying the specifications for new motors in the electric motor technology choice submodule.

Energy Policy Act of 1992 (EPACT1992)

EPACT1992's efficiency standards for boilers, furnaces, and electric motors affect the IDM. The IDM assumes 80% efficiency for natural gas burners and 82% for oil burners. These efficiencies meet the EPACT1992 standards. EPACT1992 requires minimum efficiencies for all motors up to 200 horsepower purchased after 1998. The choices offered in the motor efficiency assumptions are all at least as efficient as the EPACT minimums.

Clean Air Act Amendments of 1990 (CAAA1990)

CAAA1990 contains numerous provisions that affect industrial facilities. Three major categories of these provisions include:

- Process emissions
- Emissions related to hazardous or toxic substances
- Sulfur dioxide (SO_2) emissions

Process emission requirements were specified for several industries and activities (40 CFR 60). Emissions of almost 200 hazardous or toxic substances are also limited by regulation (40 CFR 63). These requirements are not explicitly represented in the NEMS IDM because they are not directly related to energy consumption projections.

The EPA is required under federal law to regulate industrial SO_2 emissions when total industrial SO_2 emissions exceed 5.6 million tons per year (Section 406 of the CAAA1990 and 42 USC 7651). Because industrial coal use (the main source of SO_2 emissions) has been declining, EPA does not anticipate that specific industrial SO_2 regulations will be required (U.S. Environmental Protection Agency, National Air Pollutant Emission Trends: 1900–1998, EPA-454/R-00-002, March 2000, Chapter 4). Further, because we do not project higher industrial coal use, we do not expect the limit on industrial SO_2 emissions to affect industrial energy consumption projections.

Maximum Achievable Control Technology for Industrial Boilers (Boiler MACT)

Air toxics are regulated through the National Standards for Hazardous Air Pollutants for industrial, commercial, and institutional boilers (Section 112 of the Clean Air Act). AEO models final regulations, known as Boiler MACT. Pollutants covered by Boiler MACT include several hazardous air pollutants:

- Hydrogen chloride
- Mercury, dioxins, and furans
- Carbon monoxide
- Particulate matter

Generally, industries comply with the Boiler MACT regulations by including regular maintenance and tune-ups for smaller facilities and emission limits and performance tests for larger facilities. Because natural gas area source boilers are exempt from regulation under Boiler MACT, the IDM adds to the cost of coal-, fuel oil-, and biomass-fired area source boilers.

Finally, the MAM models Boiler MACT as an upgrade cost. These upgrade costs are classified as nonproductive costs, which are not associated with efficiency improvements. These costs in the MAM reduce shipment values coming into the IDM.

California Assembly Bill 32: Emissions Cap-and-Trade as Part of the Global Warming Solutions Act of 2006 (AB32) as Amended by California Senate Bill 32, 2016 (SB32)

AB32 established a comprehensive, multiyear program to reduce greenhouse gas (GHG) emissions in California, including a cap-and-trade program.[24] In addition to the cap-and-trade program, AB32 authorizes:

- The low-carbon fuel standard
- Energy efficiency goals and programs in transportation, buildings, and industry
- Combined-heat-and-power goals
- Renewable portfolio standards

AEO models the cap-and-trade provisions for industrial facilities, refineries, and fuel providers. The NEMS Electricity Market Module models allowance price, representing the incremental cost of complying with AB32 cap-and-trade by a region-specific emissions constraint. This allowance price, when added to market fuel prices, effectively results in higher fuel prices in the demand sectors. The NEMS models limited banking and borrowing of allowances, as well as a price containment reserve and offsets. AB32 is not modeled explicitly in the IDM, but it enters the module implicitly through higher effective fuel prices and macroeconomic effects of higher prices, all of which affect energy demand and emissions, primarily in the Pacific Census Division.

SB32 was enacted in September 2016 and requires California regulators to plan for a 40% reduction in GHG emissions (below 1990 levels) by 2030.[25] AEO models emissions goals in the cap-and-trade program assuming a ceiling on CO_2 allowance prices to prevent infeasible solutions or extremely high allowance prices. Further cost-effective emissions reductions are not available, and the allowance price is at the price ceiling. The IDM assumes this price ceiling is slightly higher than the price of the Tier 3 Allowance Price Containment Reserve.

The cap-and-trade program is only one part of California's GHG reduction strategy. According to the California Air Resources Board, the cap-and-trade program is assumed to comprise less than 30% of total GHG emissions reductions targets.[26] Emissions reductions targeted by the other GHG reduction programs described above affect the industrial sector only indirectly.

Notes and Sources

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[20] U.S. Congress, "H.R.5376 – Inflation Reduction Act of 2022," Title I, Subtitle D—Energy Security, Sec. 13102, 117th Congress (2021-2022), became Public Law No: 117-169 on August 16, 2022.

[21] U.S. Congress, "H.R.133 - Consolidated Appropriations Act, 2021," Division EE, Title I, Subtitle C—Extension of Certain Other Provisions, Sec. 132, 116th Congress (2019-2020), became Public Law No: 116-260 on December 27, 2020.

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[23] Federal Register 79 FR 103, pp. 30934-31014, (Washington, DC, May 29, 2014).

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[25] California Global Warming Solutions Act §38566 as amended (Sacramento, California, September 8, 2016).

[26] Based on personal communication with CARB staff and calculations of Table II-3, page 43, of California Air Resources Board "The 2017 Climate Change Scoping Plant Update" (Sacramento, California, January 20, 2017).